Impact of restriction measures for greenhouse gas emission on development of electric power industry in Russia

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Abstract
This article presents results of an integrated analysis of technological capabilities and economic results of implementation of active policy on the restriction of greenhouse gas emission in the electric power industry of Russia, which is the biggest CO2 emitter in the fuel and energy complex. To accomplish this, introducing a payment for CO2 emission is considered as the main economic mechanism of a new ecological policy. The investigation incorporates a whole range of tasks on screening analysis of low- and non-carbon technologies on a carbon-avoided cost basis, system optimization of their development scales and identification of generating capacity mix improvements until 2030 with a sequential estimation of an additional investment and price load on the economy in the implementation of the ecology-emphasized development strategy of the Russian electric energy.

Keywords: GHG emissions; carbon-avoided costs; low-carbon technologies; investment and prices

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1 TECHNOLOGICAL CAPABILITIES OF REDUCING GREENHOUSE GAS EMISSION IN ELECTRIC POWER INDUSTRY AND THEIR ECONOMIC EVALUATION

The main field providing a decisive contribution to the restriction of greenhouse gas emission, along with energy efficiency is considered to be the electric power industry. In Russia, this industry is the biggest consumer of fossil fuel and currently generates about 30% of the national volume of GHG emission, including 35% of CO2 emission. Approximately two-thirds of CO2 emission volume in the electric power energy is formed from coal combustion, and one-third from natural gas combustion. At the same time, it is the electric power industry that incorporates the highest capabilities among all sectors of economic activity to implement changes in the structure and efficiency of using various power resources through time-expanding spectrum of electricity production and co-generation processes using fossil, nuclear fuel, hydropower and other renewable sources [1,2].

In terms of carbon intensity (namely, specific contribution to CO2 emission per unit of generated electricity), all the existing and advanced electric power-generating technologies can be split into three groups:

- High-carbon technologies of coal-fired power plants with supercritical or ultrasupercritical (USC) steam units possessing the highest specific CO2 emission; including power plants with coal gasification (IGCC) technologies;
- Low-carbon technologies of thermal power plants, which include modern combined cycle plants (CCGT) using gas with a less content of carbon when compared with coal, as well as combined heat-and-power plants (CHP) ensuring an efficient use of fuel in the combined production of electric power and heat. This group also includes advanced technologies of coal- and gas-fired plants with CO2 capture (up to 85–90%) and its subsequent compression, transportation and ultimate storage (CCS plants);
- Non-carbon technologies: nuclear power plants (NPP), hydropower plants (HPP), plants on renewable (wind, solar, geothermal) energy sources (RES plants) providing production of electric power with a zero CO2 emission, as well as electric plants using wood or agricultural biomass whose combustion emission is not accounted within the national cadastre of GHG emissions.
These groups of generating technologies differ fundamentally in the value of specific CO₂ emissions, cost and performance data (Table 1). A coal-fired USC power plant has been accepted as a ‘reference’ plant to compare other low- and non-carbon technologies. A difference between specific emissions from the ‘reference’ and any alternative low- and non-carbon technologies makes up the so-called volume of ‘avoided emissions’, which is also given in Table 1.

Screening analysis of various types of electric power plants is normally made by criterion of specific cost of a unit of electric power. Both in the Russian practice and in the practice of the International Energy Agency [3], an electricity generating cost (EGC) is used as such a criterion. Its value is determined by the relation of overall discounted cost to a discounted supply of electric power throughout the lifetime of generating technology. In its turn, overall costs are determined as a sum of capital, fuel and other variable and fixed operation and maintenance expenses.

However, in the evaluation of economic efficiency of power technologies to reduce GHG emission, a somewhat different criterion is usually used, namely a carbon-avoided cost [4,5]. Its value is determined as a difference of EGC of the basic and alternative generating technologies referring to a respective specific value of ‘avoided emissions’.

The cost estimation of carbon-avoided cost for CHP producing electric and thermal power in one technological cycle (named as ‘CHP supply scheme’) is somewhat more complicated. A so-called separate heat-and-power supply scheme consisting of a combination of a coal-condensing power plant (coal CPP) and gas-fired boiler-house plant is considered to be the ‘reference’ one for CHP.

For each of these two heat-and-power supply schemes (‘separate’ and ‘combined’), overall discounted costs are determined, provided that both power supply concepts are equalized by annual volume of heat delivery (heat output of a boiler-house plant equals the heat extraction load of CHP turbines), electric capacity (installed capacity of coal CPP and CHP are equal) and electricity output. As a rule, CHP annual capacity factor is lower when compared with the base-load coal CPP. Therefore, when equalizing the electricity output from the ‘combined’ heat-and-power supply scheme with the electricity output from the coal CPP, ‘additional’ electricity is added to the lower annual CHP output, which ensures the same electricity output for both the heat-and-energy supply schemes. It is assumed that this ‘additional’ electric energy is also generated at coal CPP, and in the estimation of overall discounted costs for the ‘combined’ scheme, it is accounted at a price equal to variable costs of coal CPP.

An annual volume of CO₂ emissions from CHP and alternative ‘separate’ heat-and-energy supply scheme is calculated based on the total fuel consumption for electricity and heat production. For a ‘separate’ scheme, annual fuel consumption is determined through a coal CPP and boiler-house plant heat rates. In the calculation of fuel consumption in a ‘combined’ scheme, CHP heat rates for electricity and heat are used, as well as fuel consumption for the generation of ‘additional’ electricity at coal CPP is required for equalizing the outputs of both the schemes.

Calculation of a carbon-avoided cost for CHP is made based on a relation of differences of non-specific, but absolute values of overall discounted costs and volumes of CO₂ emission for separate and combined heat-and-energy supply schemes.

Figure 1 depicts actualized estimates of ranges of carbon-avoided costs for various types of generating technologies at the 2020 level, taking into account an uncertainty of capital costs and domestic fuel prices within this period. All economic results provided in this paper are given in constant US dollars of 2007.

### Table 1. Cost and performance data of generating technologies and CO₂ emissions.

<table>
<thead>
<tr>
<th>Generating Technology</th>
<th>Overnight capital costs ($/kW)</th>
<th>Efficiency (%)</th>
<th>Own consumption (%)</th>
<th>Specific CO₂ emissions (ton CO₂/MWh)</th>
<th>Avoidable CO₂ emissions (ton CO₂/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal CPP (USC)</td>
<td>2100</td>
<td>47</td>
<td>5.0</td>
<td>0.73</td>
<td>–</td>
</tr>
<tr>
<td>Coal CPP (USC) with CCS³</td>
<td>3550</td>
<td>35</td>
<td>18.0</td>
<td>0.10 (0.96)</td>
<td>0.65</td>
</tr>
<tr>
<td>CCGT</td>
<td>1250</td>
<td>55</td>
<td>2.0</td>
<td>0.37</td>
<td>0.36</td>
</tr>
<tr>
<td>CCGT with CCS³</td>
<td>2500</td>
<td>47</td>
<td>7.0</td>
<td>0.04 (0.42)</td>
<td>0.68</td>
</tr>
<tr>
<td>IGCC</td>
<td>2300</td>
<td>52</td>
<td>6.0</td>
<td>0.41</td>
<td>0.32</td>
</tr>
<tr>
<td>IGCC with CCS³</td>
<td>3100</td>
<td>43</td>
<td>15.0</td>
<td>0.05 (0.49)</td>
<td>0.68</td>
</tr>
<tr>
<td>NPP</td>
<td>2600</td>
<td>34</td>
<td>6</td>
<td>–</td>
<td>0.73</td>
</tr>
<tr>
<td>Wind</td>
<td>1600 (1850)²</td>
<td>–</td>
<td>1</td>
<td>–</td>
<td>0.73</td>
</tr>
</tbody>
</table>

³Values in brackets denote estimated emission at lower efficiency before CO₂ capture.

CO₂ capture coefficient is 90%.

²Values in brackets denote capital costs of onshore wind.

⁴Integrated fuel utilization rate for electricity and heat production.

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Analysis of economic ranking shows that three basic generation technologies (nuclear power plant, as well as CCGT and gas-fired CHP) within a wide range of uncertainty have the least carbon-avoided costs (up to 30–40 $/ton of CO₂, that is approximately consistent with a cost of emissions in EU anticipated by 2020 [6]), and they are eventually equally effective alternatives for CO₂ reductions in the Russian electric power sector. Another comparatively inexpensive alternative is the development of thermal power plants using biomass. For them a wide range of carbon-avoided costs is primarily determined by a high uncertainty of the cost of local biomass resources.

The other low- and non-carbon technologies appear to be less competitive with NPP, CCGT and CHP due to significantly higher carbon-avoided costs. For wind power plants, it is caused by the low capacity factors. For thermal power plants with CCS, critical factors are a significant growth of capital costs (by 60–80% for coal plants and by two times for CCGT) and own electricity consumption needs to recover sorbents (by 13–15 percentage points for coal plants with CCS and by 5 percentage points for CCGT) [4]. Besides, the carbon-avoided cost for CCS plants shall be added with the expenditures connected with CO₂ transportation and final storage in the geological beds or worked-out oil-and-gas minefields, which will be noticeably higher than the European cost with regard to the length of the territory of Russia and a distance of potential disposal sites.

High costs of ‘avoidable emissions’ for power plants on renewable energy sources and ‘clean’ coal plants with CCS are a serious obstacle for their growth, specifically under conditions of a competitive market. Even with regard to an expected cheapening of these technologies as they are widely implemented, their competitiveness can be ensured only through special measures of economic encouragement. The most obvious measures (actively used in many member countries of the Kioto protocol) are evident or implicit subsidies of the owners of ‘green’ electric power plants at the expense of budget or at the expense of consumers collected as an additional charge in the final electricity price. However, a more integrated approach by its effect is the introduction of payment for CO₂ emission, acting as a unique tax penalty on the usage of fossil fuel.

2 STRUCTURAL CHANGES IN THE ELECTRIC POWER INDUSTRY WITH VARIOUS SCENARIOS LIMITING GHG EMISSION

A system-based evaluation of changes in the structure of generating capacities, production of electric power and centralized heat, with impact of CO₂ emissions payment, was performed using the EPOS–linear programming (LP) model to jointly optimize the development of electric power industry and fuel supply industries. The EPOS model is developed by the Energy Research Institute and solves LP task with a planning horizon of 30–40 years. This makes it possible to take into account an end-effect and obtain an adequate economic ground for strategic solutions on developing and generating network capacities adopted for the nearest 10–20 years.

A list of variables and balance constraints of EPOS ensures a system-based review and economic ranking of a set of investment alternatives on technical upgrading of the existing electric power plants and (green-field or brown-field) construction of new electric power plants of a different type (HPP, NPP, CPP and CHP on gas and coal, RES plants), boiler-houses and new intersystem power transmission lines with regard to: (i) uncertainty of their coat and performance data, (ii) limited volumes of investment resources, (iii) limited volumes of GHG emission and (iv) ensuring balance conditions for demands in generating capacity, electricity, centralized heat and fuel supply to
domestic and export markets across the main energy consuming regions of Russia.

A selection of optimum solution in the EPOS model is determined by a criterion of economic efficiency of electric power industry development as part of projected regional energy balances. As a result, a primal solution of joint optimization of gas, steam coal, electricity and generating capacity balances determines the dynamics of production capabilities in electric power industry, gas and coal industries based on the minimization of total discounted costs for their operation and development. Concurrently with that, based on a dual solution of LP optimization task, a mutually agreed and regionally differentiated system of wholesale electricity and fuel prices can be obtained, corresponding to long-term marginal costs in the energy sector.

The scenario corresponding to the parameters of so-called innovative scenarios of national economy and energy sector development provided in the Energy Strategy of Russia until 2030 [7] was adopted as a ‘BASE’ case for a following multicase optimization. The implementation of this scenario provides for serious changes in the production structure of the electric power industry, although they are not accompanied by introducing a payment for CO2 emissions or other dedicated economic measures for reducing GHG emission.

The main development trend of electric power industry in the ‘BASE’ case for a period until 2030 will be the growth of nuclear generation share from 16% in 2005 to 28% (Table 2). With a common decrease of a share of thermal generation in electricity production structure, the output of coal CPP will be intensively growing, their part will be increased from 10% to 16%. CHP dynamics will be determined by extremely moderate growth of demand in centralized heating. Even provided that CHP ensures the main growth of demand for heating, their share in the electricity production will be reduced from 37% to 23%.

An increase of the share of non-fuel types of power plants, as well as noticeable reduction of heat rates in thermal generation owing to a large-scale introduction of CCGT equipment and state-of-the-art coal units will noticeably keep down the consumption of fossil fuel. If the electricity production output is doubled, by 2030 fuel consumption will be increased by approximately 1.5 times and will be near 11.8 EJ. In this case, a share of gas in the ‘fuel mix’ of electric power industry will be decreasing from 72% in 2005 to 61% by 2030 due to a more active development of coal generation (Table 3).

A suppression of growth of fuel consumption slows down GHG emission, but at the same moment, a growing fraction of coal will contribute to its additional increase. As a result of multidirectional action of these factors annual CO2 emissions from electric power plants will increase by 60% by 2030 compared with 2005 and will reach 817 million tons.

It is important to note that technological and structural changes provided in the ‘BASE’ case make it possible to greatly reduce CO2 emission level in the electric power industry when compared with a business-as-usual (‘BAU’) case assuming the maintenance of current structure of electricity production (with very much lower part of non-fuel power plants) and the existing efficiency (or heat rates) of thermal power plants. As shown in Table 3, the implementation of ‘BAU’ case would result in the growth of fuel consumption in 2030 by 2.1 EJ and CO2 emission by 160 million tons, i.e. nearly 20% higher than the level of ‘BASE’ case.

Possibilities of additional reduction of GHG emissions when introducing payment for CO2 emissions were studied within a wide range of growth of its values. In all cases, payments are introduced after 2015, and by 2020, ‘cost’ of a unit of GHG emission will be 10–50 $/ton CO2, and in 2030 it will be 25–100 $/ton CO2 (see ‘30–25’ case to ‘30–100’ case in Table 4).

As shown by the optimization results, in this case, serious economical incentives appear for structural shifts in the electric power industry till 2030 due to the reduction of a fraction of condensing thermal power plants. Primarily, it concerns a reduction of a fraction of coal CPP (from 16% to 8–12%), the efficiency of which replacement becomes economically obvious. At the same time, as shown in Table 5, a fraction of gas CPP is

### Table 2. Key figures of ‘BASE’ case of electric power industry development.

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity production (TWh)*</td>
<td>931</td>
<td>985</td>
<td>1394</td>
<td>1843</td>
</tr>
<tr>
<td>Hydro power plant b</td>
<td>170</td>
<td>151</td>
<td>191</td>
<td>202</td>
</tr>
<tr>
<td>Nuclear power plant</td>
<td>150</td>
<td>174</td>
<td>292</td>
<td>523</td>
</tr>
<tr>
<td>Thermal power plants including:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CHP, including:</td>
<td>343</td>
<td>371</td>
<td>425</td>
<td>436</td>
</tr>
<tr>
<td>on gas (and fuel oil)</td>
<td>201</td>
<td>209</td>
<td>276</td>
<td>278</td>
</tr>
<tr>
<td>on coal (and other solid fuel)</td>
<td>142</td>
<td>163</td>
<td>149</td>
<td>158</td>
</tr>
<tr>
<td>CPP, including:</td>
<td>268</td>
<td>288</td>
<td>485</td>
<td>682</td>
</tr>
<tr>
<td>on gas (and fuel oil)</td>
<td>175</td>
<td>177</td>
<td>263</td>
<td>380</td>
</tr>
<tr>
<td>on coal (and other solid fuel)</td>
<td>93</td>
<td>112</td>
<td>221</td>
<td>302</td>
</tr>
<tr>
<td>Heat from CHP and boiler-house plants (EJ)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>5.28</td>
<td>5.02</td>
<td>5.47</td>
<td>6.07</td>
</tr>
<tr>
<td>CHP</td>
<td>2.50</td>
<td>2.40</td>
<td>2.82</td>
<td>3.09</td>
</tr>
<tr>
<td>Boiler-house plants</td>
<td>2.78</td>
<td>2.62</td>
<td>2.65</td>
<td>2.97</td>
</tr>
</tbody>
</table>

*Centralized electric power supply zone.

### Table 3. Fuel consumption and CO2 emission in ‘BASE’ and ‘BAU’ cases of electric power industry development.

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption of power plants (EJ)*</td>
<td>8.06</td>
<td>8.35</td>
<td>10.37</td>
<td>10.99</td>
</tr>
<tr>
<td>Gas</td>
<td>5.54</td>
<td>5.36</td>
<td>6.50</td>
<td>6.86</td>
</tr>
<tr>
<td>Coal</td>
<td>2.05</td>
<td>2.49</td>
<td>3.37</td>
<td>3.66</td>
</tr>
<tr>
<td>Fuel oil and others</td>
<td>0.47</td>
<td>0.47</td>
<td>0.53</td>
<td>0.47</td>
</tr>
<tr>
<td>CO2 emission (Mt)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>535</td>
<td>566</td>
<td>712</td>
<td>759</td>
</tr>
<tr>
<td>Gas</td>
<td>308</td>
<td>299</td>
<td>361</td>
<td>381</td>
</tr>
<tr>
<td>Coal</td>
<td>193</td>
<td>234</td>
<td>317</td>
<td>345</td>
</tr>
<tr>
<td>Fuel oil and others</td>
<td>34</td>
<td>33</td>
<td>34</td>
<td>32</td>
</tr>
</tbody>
</table>

*Centralized electric power supply zone.
also reduced from 21% to 15–17%. The efficiency of replacing gas CPP is determined by the fact that the carbon-avoided costs for competitive gas CHP and NPP are comparable or lower (Figure 1). The introduction of payment for CO2 emission provides an additional impetus for developing CHP generation in Russia. A share of CHP in the total production of electric power increases from 23% in a ‘BASE’ case to 27–31%. At this, the share of CHP is also growing in a centralized heat balance pushing out an application of a separate heat-and-power supply scheme and reducing the share of boiler-house plants in heat production structure. A fraction of non-carbon sources (HPP, NPP and RES) increases something like this (from 39% to 41–46%), specifically when payment for emissions is more than 50 $/ton of CO2. A relatively slight additional increase of nuclear generation is caused by the fact that in the ‘BASE’ case itself an intensive development of NPP is envisaged.

A total fuel consumption at all levels of payment for CO2 emissions will be lower than in the ‘BASE’ case, with a noticeable reduction of coal and successive increase of gas share. As shown in Table 6, at a maximum level of payment in 2030 a structure of ‘fuel mix’ in the electric power industry eventually goes back to up to date, and a total consumption of fossil fuel decreases by more than 10% when compared with the ‘BASE’ case. At all emission payment levels, an absolute volume of gas consumption in the electric power industry will be higher than in the ‘BASE’ case. Therefore, the introduction of additional ecological constraints noticeably complicates the task of forming the rational scenarios of electric power industry development corresponding to requirements of the energy strategy for the diversification of structure of consuming primary energy resources and reducing gas share in the electric power industry.

A total reduction of CO2 emission in 2030 can amount up to 140 million tons of CO2, i.e. up to 20% from emission volumes in the ‘BASE’ case (Table 6). A minimum payment for emissions (25 $/ton CO2 per option 1) will ensure 37% of this volume (more than 50 million tons), the same amount will be provided by its increase up to 50 $/ton CO2. However, a higher payment level gives a very less effect. It is important to note that an emission reduction is relative, an annual emission reduction when compared with the ‘BASE’ case, but its absolute volumes increase until 2030 at any payment level (only in ‘30–100’ case at a maximum payment of 100 $/ton CO2 their stabilization is almost reached).

A sequential decrease of coal share in a ‘fuel mix’ of electric power industry will cause a noticeable reduction of its contribution to CO2 emission from the electric power plants (Table 6). If in the ‘BASE’ case the coal burning gives more than 45% of emissions in the industry in 2030, in the alternative options this fraction decreases up to 32–39%. In this case, the main emission volume as at the present time will be determined by gas burning.

Table 5. Parameters of electric power industry development in 2030 at different levels of payment for CO2 emissions.

<table>
<thead>
<tr>
<th>Cases</th>
<th>2010</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity production (TWh)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>931</td>
<td>1843</td>
<td>1843</td>
<td>1843</td>
</tr>
<tr>
<td>Hydro power plants</td>
<td>170</td>
<td>202</td>
<td>226</td>
<td>267</td>
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<tr>
<td>Nuclear power plant</td>
<td>150</td>
<td>523</td>
<td>531</td>
<td>569</td>
</tr>
<tr>
<td>Thermal power plants, including:</td>
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<td></td>
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<td></td>
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<tr>
<td>CHP, including:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>on gas (and fuel oil)</td>
<td>343</td>
<td>436</td>
<td>493</td>
<td>523</td>
</tr>
<tr>
<td>on coal (and other solids)</td>
<td>142</td>
<td>158</td>
<td>151</td>
<td>146</td>
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<tr>
<td>CPP, including:</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>on gas (and fuel oil)</td>
<td>268</td>
<td>682</td>
<td>594</td>
<td>484</td>
</tr>
<tr>
<td>on coal (and other solids)</td>
<td>175</td>
<td>380</td>
<td>381</td>
<td>313</td>
</tr>
<tr>
<td>Heat from CHP and boiler-house plants (EJ)</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Total</td>
<td>5.28</td>
<td>6.07</td>
<td>6.07</td>
<td>6.07</td>
</tr>
<tr>
<td>CHP</td>
<td>2.50</td>
<td>3.09</td>
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<td>3.41</td>
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<tr>
<td>Boiler-house plants</td>
<td>2.78</td>
<td>2.97</td>
<td>2.78</td>
<td>2.66</td>
</tr>
</tbody>
</table>

aCentralized electric power supply zone.
bIncluding also other RES plants.
At relatively low differences in gas consumption across the cases, a volume of CO₂ emission caused by gas burning at the electric power plants in 2030 will also be changed within a rather narrow range (420–430 Mt). However, in percentage ratio, if in the ‘BASE’ case in 2030, gas gives nearly a half of CO₂ emissions from the electric power industry, then when going back to a report structure of fuel consumption in the cases with payment for CO₂ emissions, gas contribution to emission will also go back to a reported level and will amount to 56–63%.

3 ECONOMIC CONSEQUENCES OF GHG EMISSION REDUCTION SCENARIOS IN ELECTRIC POWER INDUSTRY

The shifts identified in the production structure and fuel balance of the electric power industry exercise a significant influence on the parameters of the investment and price policy. An integrated financial and economic evaluation of the case of electric power industry development in the range of CO₂ emission payments is made using the ELFIN model, which determines the dynamics of cash flows from the operational, investment and financial activities, forecasts an industry financial plan, selects a rational structure of investment financing, and predicts the necessary levels of electricity (and heat) prices providing the feasibility of proposed investment and production programme.

Changes in the structure of generating capacities caused by payment for CO₂ emissions will result in additional investments in more expensive projects of non-fuel plants and CHP having lower or zero CO₂ emissions. If in the ‘BASE’ case, total investments in electric power plants within a period until 2030 will be $363 billion, at a minimum level of emission payment (‘30–25’ case), the investment growth will be about $9 billion, and at a maximum level (‘30–100’ case) it will be $86 billion. As the payment for CO₂ increases, additional emission reduction will require even higher investment costs, which is illustrated by a curve of ‘capital intensity’ of an additional unit of emission reduction (Figure 2). A more simple approximation by a linear trend (with a quite good coincidence $R^2 \approx 0.96$) shows that ‘at the average’ to reduce CO₂ emissions relative to the ‘BASE’ case by 10 million tons will require more than $7 billion.

The impact of payment for CO₂ emissions seriously changes the structure of revenue requirements of the thermal power plants and the entire industry. As shown in Table 7, by 2030, annual payments of electric power plants for CO₂ emission will appear to be comparable to the cumulative additional investments for emission reduction.

By 2030, the volumes of payment for CO₂ emissions also appear to be comparable with the total fuel costs. Thus, at 50 $/ton CO₂ they constitute more than a half of total fuel costs, and at 75–100 $/ton CO₂ they come close to or even exceed them. Actually, this means that the introduction of payment for GHG emissions required as an additional tax for thermal

<table>
<thead>
<tr>
<th>Fuel consumption of power plants (EJ)</th>
<th>2030</th>
<th>'BASE'</th>
<th>'30–25'</th>
<th>'30–50'</th>
<th>'30–75'</th>
<th>'30–100'</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>5.54</td>
<td>7.30</td>
<td>7.76</td>
<td>7.62</td>
<td>7.71</td>
<td>7.71</td>
</tr>
<tr>
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<td>2.05</td>
<td>4.01</td>
<td>3.19</td>
<td>2.72</td>
<td>2.46</td>
<td>2.31</td>
</tr>
<tr>
<td>Black oil fuel and others</td>
<td>0.47</td>
<td>0.62</td>
<td>0.64</td>
<td>0.64</td>
<td>0.67</td>
<td>0.67</td>
</tr>
<tr>
<td>CO₂ emission (Mt)</td>
<td>535</td>
<td>817</td>
<td>765</td>
<td>711</td>
<td>691</td>
<td>677</td>
</tr>
<tr>
<td>Coal</td>
<td>193</td>
<td>379</td>
<td>302</td>
<td>257</td>
<td>233</td>
<td>219</td>
</tr>
<tr>
<td>Fuel oil and others</td>
<td>34</td>
<td>32</td>
<td>33</td>
<td>31</td>
<td>30</td>
<td>29</td>
</tr>
</tbody>
</table>

*Centralized electric power supply zone.
power plants will equal the growth of fuel costs in the industry by 1.5–2 times by 2030.

The increase of operational and investment expenses in the cases with a payment for CO2 emissions will require a growth of electricity price relative to the ‘BASE’ case: by 2030, it will be from 10% to 55%. A generalized analysis of sensitivity of electricity price to volume of emission reduction shows that on average, the emission reduction by 10 million tons of CO2 will result in a rise in electricity price by 0.4–0.5 cent/kWh (Figure 3).

Therefore, the study showed a high sensitivity of production, investment and price parameters of electric power industry to measures of economic stimulation of CO2 emission limitation by introducing a payment for emissions. Possible shifts in the production structure, fuel consumption mix, investment and price impacts of the industry, certainly have an inter-sector and macroeconomic scale and require an integrated evaluation of consequences for the national economy as a whole (see an example in Russian Energy Strategy [7]).

4 CONCLUSION

The performed analysis of capabilities and consequences of the measures limiting GHG emissions from the electric power industry provides definite grounds to generate a reasonable ecological policy in the industry leading not to serious macroeconomic damages. The basic strategic trends in the industry are an increase of a fraction of nuclear power industry with a concurrent increase of efficiency of thermal power plants. If the electricity production is doubled, this will make it possible to increase the fuel consumption by only 50% and will limit the growth of annual CO2 emission approximately by 160 million tons when compared with the BAU case.

The introduction of payment for CO2 emissions, as shown by model optimization results, can really become a serious economic incentive for deeper structural changes to the advantage of low- and non-carbon technologies, development of non-fuel sources and most efficient CHP fossil fuel technologies. The structural and technological shifts will ensure the reduction of overall fuel consumption, but will contribute to the preservation of a high fraction of gas in the ‘fuel mix’ of the industry and increase of absolute volumes of its consumption. This will make it possible to significantly (up to 140 million tons or up to 20%) reduce emissions against the ‘BASE’ case, although in absolute terms they will keep growing or in the best case they will be stabilized.

The financial-economic evaluation of options limiting CO2 emissions in the electric power industry with the introduction of payment for emissions showed a need for a significant correction of parameters of investment and price policy. Thus, a ‘capital intensity’ of an additional unit of emission reduction on average will be more than $7 billion per 10 million tons of CO2. Additional ecological payments of thermal power plants will greatly increase the cost of electricity produced at thermal power plants, reaching 50–100% of fuel costs and seriously deteriorating competitiveness of thermal (especially coal) generation. The growth of investment and operational expenses will be inevitably reflected both in the increase of electricity and heat prices. The obtained assessments demonstrate that a
reduction of CO₂ emission in the electric power industry per each 10 million tons of CO₂ will lead to an increase of price of electrical energy on average by 0.4–0.5 cent/kWh.

These results will allow performing a more general macroeconomic analysis and justification of an acceptable level of obligations of Russia by content of acceptable level of GHG emission, based on the calculations determined by these obligations of changes of dynamics of growth rates and structural changes in the national energy sector and slowdown in the Russian economic growth (see [8] for the further details).

Proposed methodology for system-wide technical and economic investigation of GHG abatement measures in the national power sector seems to be rather general for its application in other countries using different types of mathematical models and analytical tools. But in any specific case, quantitative results such as technologies with the lowest carbon-avoided costs, future generating capacity mix, impacts on investment and electricity prices will be very different because of the different values of main input factors: fuel and electricity prices, capital costs, geographic and climate conditions, present technological structure of power plants, economic measures proposed for GHG abatement, and so on. Correspondingly, modelling results and final recommendations for policy-makers cannot be simply extrapolated from one country to other and must be thoroughly defined and justified at the national level.

REFERENCES